State of Utah

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

Department of
Environmental Quality

William J. Sinclair
Acting Executive Director

DIVISION OF AIR QUALITY
Cheryl Heying
Director

DAQE-IN0105720022-09

March 5, 2009

Chris Kaiser
Kennecott Utah Copper Corporation
4700 Daybreak Parkway
South Jordan, UT 84095

Dear Mr. Kaiser:

Re: Intent to Approve: Modify AO DAQE-AN0105720020-08 to Replace Emergency Fire Pump
Salt Lake County; CDS A; Nonattainment or Maintenance Area, PM_{10} SIP / Maint Plan
Project Number: N010572-0022

The attached document is the Intent to Approve for the above-referenced project. The Intent to Approve is subject to public review. Any comments received shall be considered before an Approval Order is issued. The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an Approval Order. An invoice will follow upon issuance of the final Approval Order.

Future correspondence on this Intent to Approve should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is Nando Meli Jr., who may be reached at (801) 536-4052.

Sincerely,

Ty L. Howard, Manager
New Source Review Section

TLH:NM:kw

cc: Mike Owens
Salt Lake Valley Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE: Modify AO DAQE-AN0105720020-08 to Replace Emergency Fire Pump

Prepared By: Nando Meli Jr., Engineer
Phone: (801) 536-4052
Email: nmeli@utah.gov

INTENT TO APPROVE NUMBER

DAQE-IN0105720022-09

Date: March 5, 2009

Power Plant/ Lab/ Tailings Impoundment

Source Contact:
Mr. Ray Gottling
Phone: (801) 569-7110

Ty L. Howard, Manager
New Source Review Section
Utah Division of Air Quality

ABSTRACT

Kennecott Utah Copper Corporation (KUCC) has requested approval to replace the diesel powered fire pump at the power plant. Currently they have a 138 Hp pump and have requested approval to replace it with a 175 Hp pump. This is an emergency fire pump and they have requested a limit of 300 hours per rolling 12-month period for routine maintenance and testing operation of the pump.

Salt Lake County is a Non-attainment area of the NAAQS for PM_{10} and SO_2, and is a Maintenance area for Ozone. Title V of the 1990 Clean Air Act applies to this source and this modification will result in a Title V amendment. The requirements for the Title V shall be followed until operating permit for this source has been amended. The emissions, in tons per year (tpy), will increase as follows: PM_{10} = 0.02, NO_x = 0.24, SO_2 = 0.05, CO = 0.07, and VOC = 0.02. The changes in tpy emissions will result in the following potential to emit totals: PM_{10} = 257.22, NO_x = 3,764.14, SO_2 = 6,219.25, CO = 102.38, VOC = 11.13 and HAPs = 2.24.

The NOI for the above-referenced project has been evaluated and has been found to be consistent with the requirements of UAC R307. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Executive Secretary of the Utah Air Quality Board.

A 30-day public comment period will be held in accordance with UAC R307-401-7. A notification of the intent to approve will be published in the Salt Lake Tribune and Deseret News on March 10, 2009. During the public comment period the proposal and the evaluation of its impact on air quality will be available for the public to review and provide comment. If anyone so requests a public hearing, it will be held in accordance with UAC R307-401-7. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated. The proposed conditions of the AO may be changed as a result of the comments received.

Name of Permittee:	**Permitted Location:**
Kennecott Utah Copper Corporation 4700 Daybreak Parkway South Jordan, UT 84095	Power Plant/ Lab/ Tailings Impoundment 9600 West 2100 South Magna, UT 84044

UTM coordinates:405000 m Easting, 4506000 m Northing
SIC code:4911 (Electric Services)

Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five years. [R307-401]. [R307-415-6b]

I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6 The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

I.7 The owner/operator shall comply with UAC R307-107. General Requirements: Unavoidable Breakdowns. [R307-107]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

II.A.1 **Plant Wide**
Power Plant

II.A.2 **Power Plant Boiler #1**
Rated at:
431 MMBTU/hr maximum heat input when burning coal
453 MMBTU/hr maximum heat input when burning natural gas

II.A.3 **Power Plant Boiler #2**
Rated at:
431 MMBTU/hr maximum heat input when burning coal
453 MMBTU/hr maximum heat input when burning natural gas

II.A.4 **Power Plant Boiler #3**
Rated at:
431 MMBTU/hr maximum heat input when burning coal
453 MMBTU/hr maximum heat input when burning natural gas

II.A.5 **Power Plant Boiler #4**
Rated at:
838 MMBTU/hr maximum heat input when burning coal
872 MMBTU/hr maximum heat input when burning natural gas

II.A.6 **Hot Water Boiler**
7.133 MMBTU/hr natural gas fired boiler, located in the laboratory

II.A.7 **Cold Solvent Parts Washers**
25 gal. per washer and approximately 200 gal. or less of solvent used every year for maintenance cleaners at various locations throughout the source.

II.A.8 **Wet Cooling Towers**
Five Non-contact water-cooling towers

II.A.9 **Natural Gas Generator**
1.2 MMBTU/hr natural gas fired generator, located in the Power Plant

II.A.10 **Hydraulic Coal Unloader System with Diesel Engine**
Manufacturer John Deere
Maximum Rating 170 Hp

II.A.11 **Coal and Ash Handling Equipment**
Wet and closed fly ash capture system, handles ash from the electrostatic precipitators

II.A.12 **Diesel Engine**
175 Hp Diesel Engine located in the Power Plant, to operate an emergency fire water pump

II.B Requirements and Limitations

II.B.1 **Plantwide Conditions**

II.B.1.a The sulfur content of any fuel burned shall not exceed 0.52 lb of sulfur per million BTU (annual running average), nor shall any one test exceed 0.66 lb of sulfur per million BTU.

A. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing. Fuel lot size is defined as the weight of fuel consumed during three operational hours.

B. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.

C. Failure of KUCC to measure at least 95% of the required increments in any one month shall constitute a violation of this provision.

D. KUCC shall submit monthly reports of sulfur input to the boilers. The reports shall include sulfur content, gross calorific value and moisture content of each gross coal sample; the gross calorific value of all coal and gas; the total amount of coal and gas burned; and the running annual average sulfur input calculated at the end of each month of operation.

Conditions II.B.1.a.A, II.B.1.a.B, and II.B.1.a.C above may be replaced by an alternative testing plan for use with a given source of coal in accordance with R307-203-1
[R307-401]

II.B.1.b Visible emissions from the boiler stacks shall not exceed the associated opacity on a six-minute average, based on 40 CFR 60, Appendix A, Method 9, or as measured by a CEM, except as provided for in R307-201 and R307-305:

Natural Gas Fuel	10% opacity
Coal and Oil Fuel	20% opacity

Visible emissions from the following types of stationary sources shall not exceed the associated opacity on a six minute average, based on 40 CFR 60, Appendix A, Method 9:

Baghouses	10% opacity
Fugitive Emissions	15% opacity
Fugitive Dust and Diesel Engines	20% opacity

[R307-201]

II.B.2 **<u>Boiler Conditions</u>**

II.B.2.a During the period from November 1, to the last day in February of the following year, inclusive, the following conditions shall apply:

A. The four boilers shall use only natural gas as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. If the power plant is in operation using natural gas when the curtailment is imposed, the power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Executive Secretary shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.

B. The following consumption limit on fuel usage shall not be exceeded:

1) 42,706 MMBTU per day for natural gas usage

2) 31,510 MMBTU per day for coal usage.

To determine compliance with a daily limit KUCC shall calculate a daily limit. The BTU limit shall be determined by monitoring the daily natural gas, and/or coal consumption and multiplying that value with the BTU rating of the fuel consumed. The natural gas BTU used shall be that value supplied by the natural gas vendor from the previous month's bill. The BTU limit for coal shall be determined by monitoring the daily coal consumption and multiplying that value with the coal BTU rating. Appendix A outlines how the coal BTU rating is calculated. KUCC shall provide test certification for each load of coal received. Test certification for each load received shall be defined as test once per day for coal received that day from each supplier. Certification shall be either by their own testing or test reports from the coal marketer. Records of BTU fuel usage shall be kept on a daily basis. [R307-401]

C. Natural gas used as fuel.

Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 0.004 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 159 lb/hr
- 336 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:

a) PM_{10} - 0.004 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 306 lb/hr
- 336 ppmdv (measured at 3% oxygen)

D. Coal used as fuel.

During a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 17.3 lb/hr
- 0.029 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 216 lb/hr
- 426.5 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:

a) PM_{10} - 33.5 lb/hr
- 0.029 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 377 lb/hr
- 384 ppmdv (measured at 3% oxygen)

E. KUCC shall provide monthly reports to the Executive Secretary showing daily total emission estimates based upon boiler usage, fuel consumption and previously available results of stack tests
[R307-401]

II.B.2.b During each annual period from March 1 to October 31, inclusive, the following conditions shall apply:

A. KUCC shall use coal, natural gas, and/or oils that meet all the specifications of 40 CFR

266.40(e) and contains less than 1000 ppm total halogens, and/or number two fuel oil or lighter in the boilers.

B. The following consumption limit on fuel usage shall not be exceeded:

50,400 MMBTU per day of heat input

To determine compliance with a daily limit KUCC shall calculate a daily limit. The BTU limit shall be determined by monitoring the daily natural gas, and/or coal consumption and multiplying that value with the BTU rating of the fuel consumed. The natural gas BTU used shall be that value supplied by the natural gas vendor from the previous month's bill. The BTU limit for coal shall be determined by monitoring the daily coal consumption and multiplying that value with the coal BTU rating. Appendix A outlines how the coal BTU rating is calculated. KUCC shall provide test certification for each load of coal received. Test certification for each load received shall be defined as test once per day for coal received that day from each supplier. Certification shall be either by their own testing or test reports from the coal marketer. Records of BTU fuel usage shall be kept on a daily basis. [R307-401]

C. Emissions to the atmosphere from each emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 17.3 lb/hr
- 0.029 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 216 lb/hr
- 426.5 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:

a) PM_{10} - 33.5 lb/hr
- 0.029 grain/dscf (68oF, 29.92 in Hg)

b) NO_x - 377 lb/hr
- 384 ppmdv (measured at 3% oxygen). [R307-401]

II.B.2.c Stack testing to show compliance with the above emission limitations shall be performed for all four boilers and the following air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see Section IX, Part H.2.a for more details), and as directed by the Executive Secretary:

	Pollutant	Method	Retest every
A.	PM_{10}	201/201a	1 year
B.	NO_x	7	1 year

The heat input during all compliance testing shall be no less than 90% of the design rate, which is 388 MMBTU/hr for boilers 1, 2, and 3, and 754 MMBTU/hr for boiler #4.

The limited use of natural gas during startup, for maintenance firings and break-in firings does not constitute operation and does not require stack testing.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location
[R307-401]

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

F. PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

G. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

H. Calculations

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation. [R307-401]

PERMIT HISTORY

The final AO will be based on the following documents:

Supersedes	Approval Order DAQE-AN0105720020-08 dated October 20, 2008

Appendix A
Coal Management Practice and BTU Calculation Method

The purpose of this coal management plan is to provide a clear method for KUCC to perform calculations of the BTU rating of coal received and burned in the KUCC Power Plant boilers.

Coal is received at the Utah Power Plant regularly by truck where it is offloaded and stored in a common stockpile. Coal is transferred to a coal feeder by a front end loader and the coal could be mixed during handling. As a result of this activity, coal fed to the boilers is a mixture of coal received. At any one time there is approximately 14 loads of coal in the stockpile.

The daily coal heat input shall be determined by daily coal consumption multiplied by the coal BTU rating. The coal BTU rating shall be determined by averaging the BTU rating of the fourteen (14) most recent test certifications for coal received from the coal vendor. This is representative of the mixing that occurs in the common coal stockpile. Certification of each coal load shall be determined by the coal vendor or by KUCC's testing.

This appendix shall be updated as necessary to reflect the current operating conditions. Approval by the Executive Secretary is required for modifications to the Appendix A Coal Management Practice and BTU Calculation Method but a modification of the AO will not be required.

ACRONYMS

The following lists commonly used acronyms and their associated translations as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
ATT	Attainment Area
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
MACT	Maximum Achievable Control Technology
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds